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Mr. David S. Guzy,
Rules and Procedures Staff
Minerals Management Service
Royalty Management Program
Denver Federal Center, Building 85
8th Street, Room C-420
Denver, CO 80225

Priority Mail
October 29, 1996

Dear Mr. Guzy:

RE: Comments on Proposed Rulemaking - Amendments to Transportation Allowance Regulations for Federal and Indian Leases to Specify Allowable Costs and Related Amendments to Gas Valuation Regulations

Marathon appreciates the opportunity to comment on the MMS' proposed rulemaking (NOPR) governing transportation costs and related gas valuation regulations for Federal and Indian leases. This NOPR was published in the July 31, 1996 Federal Register (Volume 61, Number 148), pages 39931-39940 and in the September 17, 1996 (Volume 61, Number 131), page 48872 providing an extension of public comment period from September 30, 1996 to October 30, 1996.

We would like you to consider the following comments regarding the NOPR.

Firm Demand Charges

The MMS proposes to limit the demand charge deduction to the rate per MMBtu of actual volumes moved/transported. Marathon is not clear on how the MMS would intend industry to calculate this rate, nor do we agree that the rate should be limited as a royalty deduction to the extent it is used. The demand charge or reservation charge is paid monthly regardless of whether or not actual volumes are shipped. This charge guarantees that there will be space available to ship gas in the future. It is a more expensive type of service and is billed to the shipper in a different manner than interruptible service, but it is nonetheless a cost to transport gas otherwise indistinguishable from any other transportation service. Therefore, the royalty interest should pay their share of the reservation fee regardless of whether or not gas is shipped.

Under the MMS interpretation, there remains the question of how the rate will be calculated. Do we divide the reservation fee by the 100% load factor, by the average historical MMBtu's moved, or by the actual volumes moved to get a unit rate? This needs to be clarified.

The Capacity Release Program

To be consistent with Marathon's argument for inclusion of all firm demand charges, we would support the inclusion of capacity release gains and losses as well. Otherwise, we have no comments.

Pipeline Rate Adjustments

Not only will there be an administrative burden to track rate adjustments, there will be an even larger administrative burden to keep track of all the exceptions that the MMS spells out in this NOPR. Lessees would be required to keep a separate set of accounting records just to keep up with MMS royalty payments. The lessee should be allowed to assess a "Royalty Administration Fee" to offset the costs associated with this otherwise unnecessary expense. Marathon suggests that the MMS implement a distinct transaction code or adjustment reason code for reporting these adjustments, allow the adjustments to be reported as a lump sum, and report using the sales date upon which proceeds were received by the lessee. MMS can review detail of the adjustments in subsequent audits.

Marathon takes exception to the MMS rule of royalty due on penalty refunds. Since the MMS refuses to acknowledge penalties as viable deductions for transportation, it is obviously inequitable for the MMS to expect royalty on penalty refunds. Additionally, the MMS has taken a simplified approach to the concept of rate case refunds. Most rate case refunds cannot/will not segregate each individual component that the MMS has defined as allowable in this NOPR. The necessity of both industry and MMS to differentiate the disallowable components of rate case refunds would be unduly burdensome.

The MMS needs to further define their procedures associated with interest received on pipeline refunds and/or credits. Marathon assumes that the MMS will accept the interest as payment in full, for royalty purposes, even in those instances where the rate may be less than the MMS' interest rate defined by existing regulations. MMS should also consider establishing a distinct transaction code and/or adjustment reason code to report any applicable interest.

Gas Supply Realignment Costs
No comments. With the reform/terminating of contracts, these costs will ultimately be eliminated.

Commodity Charges
No comments.

Wheeling Costs
No comments.

GRI and ACA
No comments.

Actual and Theoretical Losses
No comments.

Supplemental Services

Pipeline standards address the physical properties of gas, such as the content of CO_2, H_2S, water, nitrogen, and other inert ingredients in the gas stream. Also specified is the minimum and maximum delivery pressure and BTU content, measurement requirements, and NGL content. Gas must meet these standards or risk being rejected by the pipeline. These standards are fairly consistent between pipelines and are described in the pipelines' tariff.

What is unclear is the definition of "marketable condition." If this is the litmus test for excluding or including transportation costs, then this represents a change from how almost all of the costs addressed in this NOPR have been handled historically. Most of these services are not new; they have always been performed by the pipeline and paid for by the producer. Transportation rates are two-part rates consisting of a demand charge and a commodity charge. The demand charge is paid whether gas is transported or not. It is a sunk cost which does not affect the market clearing price of gas.

Prior to Order 636, rate design for transportation was based on the modified fixed variable method. This means that the majority of fixed costs were reflected in the commodity rate rather than the demand charge and billed out on a volumetric basis. Therefore, the commodity charge was a significant variable cost of gas and was a factor in selecting gas MMBtu's relative to other competing fuels. In order for gas to be a competitive choice and since the commodity portion of the transportation rate was fixed by regulation, the wellhead had to absorb a lower netback price. Order 636 established the straight fixed variable rate design method which loads up the demand charge portion of the transportation rate with most of the fixed costs. This change has allowed wellhead prices to strengthen because the variable cost (commodity charge) of buying gas MMBtu's is now lower. If the MMS is to be paid on a gross proceeds basis, they should share in all the costs associated with pipeline services, which in fact they have always shared because it was simply reflected in lower wellhead prices and not billed separately. Not only does the MMS propose to set up a "pipeline standards" test for allowing the deduction of costs as transportation, but further, the MMS' proposal appears to eliminate indirect costs of any type, even if genuinely associated with transportation.

In determining whether a deduction is allowed, the MMS needs to look at the intent of the services rendered, i.e., to put gas in a marketable condition or for transportation. In certain instances, gas is acceptable to the transporter and purchaser without compression; however, the compression is necessary to offset line pressure in order to maintain deliverability and effectively manage the reservoirs involved. This would obviously indicate that the costs are due to transportation, not marketing, constraints. The best test to identify a bonafide transportation cost is to ask the question, "Will this gas move if this cost is not paid?" Of course, if transportation will occur only if the cost is paid, then it is undeniably a cost of transporting gas regardless of its genesis or description

Storage

Does this mean that the lessee can sell the royalty portion of the gas stream at the earliest possible point? If so, then perhaps the most expedient and cost-effective way to treat MMS gas would be to always sell their share at the wellhead.

Short-term storage fees (parking and banking) are part of the transportation process and necessary costs to move gas. Marathon is not sure what the MMS is referring to as storage for "accounting convenience." We would like the MMS to elaborate further on their statement.

Aggragator/ Marketer Fees
No comments.

Imbalance Penalties

Royalty interests should share in all imbalance cashout penalties regardless of whether or not a portion of the imbalance exceeds the pipeline tolerance level. Imbalances are inevitable, especially with producer/marketers who are backed up directly against the supply source in the marketing chain. Obviously, the incentive is for the shipper to maximize value and therefore to avoid penalties which would reduce value. Again, this is not a situation where the shipper has a choice. Swapping imbalances is only at the pipelines' discretion and assumes you can find someone in an opposite position. Shippers cannot insist on producers entering into an operational balancing agreement; this is entirely voluntary. These options have proven to give only marginal relief to shippers' imbalance problems, but it does demonstrate FERC's anticipation that imbalances were going to be a normal operating occurrence and therefore needed to be addressed. The reality of this is many shippers exceed the tolerance level knowingly because the cashout price mechanism will pay them a higher price than they could get on the spot market. Since the implementation of the March 1, 1988 regulations, the MMS has consistently upheld the use of arm's-length contract sales as the basis for royalty value. To deviate from existing regulations on value associated with cashout sales is totally unreasonable.

Again, this has nothing to do with marketing cost. It is a cost most closely associated with the movement of gas. In most cases, at a minimum, a producer must nominate its gas into a pipeline pool in order for it to be made available for sale. Other penalties, such as operational penalties, imbalance penalties, scheduling penalties, and administrative fees, are also SHIPPER-incurred costs and in fact are new post Order 636 transportation costs that have evolved from the pipelines' change from a merchant to a common carrier.

Retroactive Date

Although the NOPR has been assembled for the purpose of addressing the Order 636 environment by the MMS suggesting a retroactive date, it appears the MMS is not keeping within their own standard of rulemaking policy for implementation of new regulations. The MMS consistently implements new regulations on a prospective basis. Marathon strongly believes the MMS should move in a prospective format on the effective date.

If you have questions regarding our comments, please contact Linda Brown at 419-421-2457.

Very truly,

Cleveland C. Woodson, Manager
Regulatory Control & Royalty Relations

CCW/LGB/srh